Decision **DRAFT DECISION OF ALJ HALLIGAN** (Mailed 4/25/2006)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation to Facilitate Proactive Development of Transmission Infrastructure to Access Renewable Energy Resources for California	Investigation 05-09-005 (Filed September 8, 2005)

OPINION ON PROCEDURES TO IMPLEMENT THE COST RECOVERY PROVISIONS OF PUBLIC UTILITIES CODE SECTION 399.25

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I. Summary[1]

In this order, we evaluate and adopt specific policies and procedures to implement the cost recovery provisions of Pub. Util. Code § 399.25. Section 399.25[2] was enacted on September 12, 2002, as part of Senate Bill (SB) 1078,[3] and is intended to facilitate California's use of renewable energy resources. Section 399.25 directs the Commission to deem necessary those transmission facilities identified in certificate applications if the proposed facilities are necessary to facilitate achievement of the State's renewable power goals. Section 399.25 also provides a "backstop" cost mechanism allowing the utilities to recover through retail rates any costs of the above facilities that are not approved by the Federal Energy Regulatory Commission (FERC) for recovery through transmission rates. Today's order clarifies how we intend to implement § 399.25 to provide the utilities and renewable resource developers with the cost recovery assurance to facilitate meeting the Renewable Portfolio Standard (RPS) goals. This decision adopts principles for implementing the requirements of § 399.25 that are in the public interest, because they will assist in our effort to ensure that California has the necessary transmission infrastructure in place in order to meet the RPS goals. The adopted principles are summarized below.

- Today's decision reaffirms our finding in Decision (D.) 03-07-033 that the provisions of § 399.25 apply to transmission facilities that come before the Commission in the form of a Certificate of Public

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1 Attachment 1 explains each acronym or other abbreviation that appears in this decision.

2 All statutory references are to the Public Utilities Code unless otherwise stated.

3 (Stats. 2002, Ch. 516), adding Article 16 (California Renewables Portfolio Standard Program) to the Cal. Pub. Util. Code § 399.11, *et seq.* (2004) (SB 1078).

Convenience and Necessity (CPCN) or Permit to Construct (PTC) application and that are deemed necessary to facilitate meeting the Renewable Portfolio Standard (RPS) goals.

- We modify our prior finding in D.03-07-033 to reflect that the provisions of § 399.25 apply to both "network"[4] transmission facilities and high-voltage, "generation-tie"[5] (gen-tie) transmission facilities that are deemed necessary to facilitate the achievement of the RPS goals.
- Findings concerning network benefits pursuant to § 399.25(b)(1) are not a prerequisite to the provision of backstop cost recovery under § 399.25(b)(4). While § 399.25(b) requires the Commission to take "all feasible actions" to ensure that the costs of transmission projects that are necessary to facilitate achievement of RPS goals are fully reflected in rates, including, but not limited to, making findings, where supported by the evidentiary record, that the transmission facilities in question provide network benefits, we find that each of the obligations listed in the four subsections of § 399.25 (b) operate independently of one another, and none is a prerequisite to any other.
- Transmission projects that meet the following qualifying criterion should be considered eligible for § 399.25 cost recovery: (1) new high-voltage, bulk-transfer, transmission facilities, whether classified as network or gen-tie, that are designed to serve multiple RPS-eligible

[4] "Network" facilities are defined in FERC Order 2003 as "additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Customer interconnects to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System."

[5] According to Order No. 2003 generation-tie facilities "include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades."

> generators[6] where it has been established that the amount of added transmission capacity will likely be utilized by RPS-eligible generation projects within a reasonable period of time, and (2) transmission upgrades that are required to connect RPS-eligible resources with approved RPS power purchase contracts.

Requests for § 399.25 cost recovery for upgrades that do not meet the above criterion will be considered on a case-by-case basis in the applicable certificate proceeding.

In adopting these principles, this decision modifies certain findings previously adopted in D.03-07-033 to reflect our further consideration and subsequent events.

II. Procedural History

On September 8, 2005, the Commission opened this Order Instituting Investigation (OII) to examine and improve the Commission's transmission planning process as it relates to renewable resources and to ensure that California has the necessary transmission infrastructure in place in order to meet the RPS goals.

On November 7, 2005, an initial prehearing conference was held and a partial procedural schedule was established. Interested parties were directed to identify the "top six" issues that need to be addressed in 2006 to facilitate renewable transmission in California and assist the utilities in meeting their 2010 RPS goals. Workshops to discuss the parties' filings followed on December 6 and 7, 2005. The December 21, 2005, the Assigned Commissioner's Ruling and

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[6] Section 399.12 (a) of Article 16 defines an "Eligible renewable energy resource" as a facility that meets the definition of "in-state" renewable electricity generation facility in Section 25741 of the Public Resources Code.

Scoping Memo (ACR) established the scope and schedule for the investigation. The ACR determined that the first priority in this proceeding should be to implement and establish the cost recovery provisions set forth in § 399.25. The ACR also determined that no evidentiary hearings would be needed to implement the backstop cost recovery provisions on § 399.25.

Briefs were filed on January 25, 2006 by Southern California Edison Company (SCE), Pacific Gas & Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), the Independent Energy Producers Association (IEP), the California Independent System Operator (CAISO), the California Wind Energy Association (CalWEA), Center for Energy Efficiency and Renewable Technologies (CEERT), The Green Power Institute and Stirling Energy Systems, Inc. (Stirling). Reply Briefs were received from SCE, PG&E, SDG&E and the CAISO (jointly as the "Joint Parties"), The Utility Reform Network (TURN), Vulcan Power Company (Vulcan), Stirling, CEERT, and CalWEA on February 17, 2006.

Today's decision is an interim order. Other high priority issues identified by the parties and Commission staff in this proceeding are currently under consideration and will be taken up as appropriate in subsequent orders and rulings.

III. Statutory Background

California SB 1078 established the California RPS Program, as generally set forth in Pub. Util. Code §§ 399.11-399.16.[7] The RPS Program requires each

[7] An act to add Sections 387, 390.1, and 399.25 to, and to add Article 16 (Sections 399.11 - 399.16) to Chapter 2.3 of Part 1 of Division 1 of, the Public Utilities Code, relating to renewable energy.

electrical corporation to procure at least 20% of its total retail electricity sales from eligible renewable energy resources by 2017. This target date was subsequently revised by the Energy Action Plan to 2010, in order to realize the benefits of renewable power more quickly.[8] SB 1078 also contains the following language, codified as § 399.25:

> 399.25. (a) Notwithstanding any other provision in Sections 1001 to 1013, inclusive, an application of an electrical corporation for a certificate authorizing the construction of new transmission facilities shall be deemed to be necessary to the provision of electric service for purposes of any determination made under Section 1003 if the commission finds that the new facility is necessary to facilitate achievement of the renewable power goals established in Article 16 (commencing with § 399.11).
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> (b) With respect to a transmission facility described in subdivision (a), the commission shall take all feasible actions to ensure that the transmission rates established by the Federal Energy Regulatory Commission are fully reflected in any retail rates established by the commission. These actions shall include, but are not limited to:
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> > (1) Making findings, where supported by an evidentiary record, that those transmission facilities provide benefit to the transmission network and are necessary to facilitate the achievement of the renewables portfolio standard established in Article 16 (commencing with Section 399.11).
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> > (2) Directing the utility to which the generator will be interconnected, where the direction is not preempted by federal law, to seek the recovery through general

8 http://www.cpuc.ca.gov/static/industry/electric/energy+action+plan/index.htm.

transmission rates of the costs associated with the transmission facilities.

(3) Asserting the positions described in paragraphs (1) and (2) to the Federal Energy Regulatory Commission in appropriate proceedings.

(4) Allowing recovery in retail rates of any increase in transmission costs incurred by an electrical corporation resulting from the construction of the transmission facilities that are not approved for recovery in transmission rates by the Federal Energy Regulatory Commission after the commission determines that the costs were prudently incurred in accordance with subdivision (a) of Section 454.

In D.03-07-033, the Commission adopted a general framework for implementing § 399.25, including:

- The provisions of § 399.25 apply to network transmission facilities that come before the Commission in the form of a CPCN or PTC application. "Network" transmission facilities are defined as those that are needed to ensure reliable electric service with the addition of generation. The provisions of § 399.25 do not apply to transmission facilities needed to bring power from the plant to the first point of interconnection with the existing transmission grid.

- The procurement proceeding will develop the rules and procedures for the RPS planning process and RPS renewables bidding program. If the transmission facility is an integral part of a renewables project approved pursuant to the RPS process, (i.e., a winning renewables bid), that creates a prima facie finding that the network upgrade will facilitate achievement of the renewable power goals set forth in Article 16 of SB 1078.

- The Commission will make § 399.25(a) and § 399.25(b)(1) findings on whether a proposed transmission project is "necessary" to facilitate achievement of renewable power goals in the applicable CPCN or PTC proceeding, based on the results of the RPS procurement process and General Order 131-D considerations of alternatives to the proposed project. The evaluation will not, however, reconsider the selection of the winning generation project.

- In the applicable CPCN or PTC proceeding, the Commission will make § 399.25(b)(1) findings regarding whether the transmission project undertaken to ensure reliable electric service with the addition of generation will also provide benefits to the transmission network.

- The Commission will continue to perform the appropriate California Environmental Quality Act (CEQA) review of CPCN and PTC applications, which may include consideration of project alternatives.

In addition, D.03-07-033 interpreted § 399.25 as allowing the Commission to direct transmission owners to pay the upfront costs of network upgrades to connect renewable energy generators. SCE applied for rehearing, arguing that FERC had exclusive authority over interconnection agreements under the transmission provisions of Federal Power Act § 791 et seq.

After the Commission denied its application for rehearing in D.03-10-040, SCE filed a petition for writ of review. In 2004, the California Court of Appeal heard SCE's case and in *Southern California Edison Co. v. PUC* (121 Cal. App. 4th 1303), overturned our decision.[9]

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[9] "The Interim Opinion and Order Denying Rehearing interpret Public Utilities Code Section 399.25 to permit a requirement that utilities pay up-front costs of system upgrades necessary to connect new sources of renewable energy to the grid. Because this interpretation is preempted by federal law, the portions of the decision in which it appears must be annulled." SCE v. PUC, 121 Cal. App.4th, 1303, 1313 (2004), review denied by the California Supreme Court (2005).

FERC's authority over interstate transmission wholesale energy sales stems from § 824 in the *Federal Power Act*. Sections 824(i) and 824(k) give FERC the authority to order interconnection to the grid and to specify the terms of the interconnection.[10] In 2003, FERC issued its Standard Interconnection Agreement Order [11]which requires generators to provide upfront funding for network transmission upgrades unless the transmission facility volunteers to pay the costs.

The Court of Appeal held that the Commission could not require transmission owners to provide upfront funding because the Federal Power Act, FERC's Order of 2003, and the history significant federal presence in the area of interconnection preempted state regulation of transmission financing. The California Supreme Court denied further review.[12] Consequently, the Commission does not have the authority to require transmission owners to fund the upfront costs of network upgrades.[13]

IV. Implementation of Section 399.25

As noted in the OII, the Commission has taken a number of steps thus far to ensure that renewable projects proposed in response to the utilities' RPS

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[10] *Id*. at 1310-11.

[11] FERC Order No. 2003, (104 FERC ¶ 61, 103).

[12] *Southern California. Edison Co. v. Public Utilities Com.*, 121 Cal. App. 4th 1303 (Cal. Ct. App., 2004), *modified and reh'g denied*, 2004 Cal. App. LEXIS 1609 (Cal. App. 2d Dist., Sept. 27, 2004), *review denied by S. Cal. Edison Co. v. PUC*, 2005 Cal. LEXIS 592 (Cal., Jan. 19, 2005).

[13] The court specifically rejected the PUC's argument that the states possessed supplemental regulatory powers under the *Federal Power Act* § 824(b)(1) by concluding that ordering upfront financing did not fall into an area of traditional state regulation such as transmission siting. *See* SCE v. PUC, 121 Cal. App. 4th at 1312.

solicitations are assessed no more and no less than their appropriate share of the incremental transmission costs for which they are responsible. In D.04-06-013, we made adjustments to the bid-ranking process to ensure that opportunities to share the costs of gen-tie facilities across projects are recognized. In D.05-07-040 we further directed the utilities to assign the costs of large transmission upgrades that would be used by more than one RPS project on a pro-rata basis for purposes of bid evaluation in the 2005 procurement process.

These directives were issued in recognition of the realities of transmission development to support renewable energy. Specifically, transmission capacity expansions necessary to access renewable energy resources are often described by a step function, in which the most economic transmission expansion to accommodate a given project exceeds the capacity required for that project. Building surplus capacity from the outset may offer economies of scale to the extent that it is reasonable to assume that additional renewable projects will come online at a later date, filling the capacity.

In D.04-06-010 we identified the Tehachapi resource area as an area in which it was necessary to adjust transmission planning to provide for an orderly, logical, and phased expansion of the transmission system based on the magnitude of the wind resource identified by the CEC, engineering and cost considerations, and recognition of other relevant factors including statewide transmission needs and other possible benefits.[14] However, generation projects that are first to market should not be encumbered by the totality of these transmission costs since to do so would lead to an overstatement of the costs for

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[14] D.04-06-010, Finding of Fact 5 at p. 43.

which a given project is actually responsible and hamstring those projects located in areas where the most economic transmission expansions far exceed the capacity needs of projects bidding into the RPS solicitation.

While our prior directives go a long way toward reconciling the bid ranking process with the general preference of building transmission as economically as possible, existing rules governing actual cost responsibility remain problematic. Current FERC policy requires a new generator to fund transmission upgrades which would not have been built but for the interconnecting generator's request. If the upgrades are classified as "network" facilities, the upgrade costs can be "rolled-in" to general transmission rates, and the transmission owner would credit back those costs, with interest, in monthly payments amortized over a number of years beginning when the new generation is available to the grid. Gen-tie costs must be funded by new generators and thus absorbed as part of the cost of producing power.

The burdens this policy places on generators may be acceptable in circumstances where no economic advantage is gained by sizing the expansion in excess of what is needed to support a known generator project. However, there are significant problems with this approach in situations where the optimally sized expansion, based on expectations of future market entry, exceeds the capacity needed to support known projects. For obvious reasons, generators are unlikely to be either willing or able to finance the totality of costs associated with large transmission upgrades intended to accommodate a significant number of other, as of yet, unknown projects.

FERC's Order No. 2003 offers a partial solution by allowing, though not requiring, transmission providers to finance network upgrades rather than requiring generators to cover these up-front costs. In circumstances where the optimally sized network upgrade to support renewable development in a region is likely to exceed the incremental capacity needs of the typical project, a utility could elect to exercise its right under the CAISO tariff, and pay for the upgrades itself.

Utility willingness to provide up-front funding for transmission upgrades is understandably contingent on some level of assurance that the costs incurred can be recovered. Under existing FERC rules, the costs of network upgrades are eligible for recovery from all transmission customers through the Transmission Access Charge (TAC), whether they are financed by the generator or by the utility.[15] In circumstances where the proposed network upgrade will expand capacity to support additional projects that have yet to manifest, the utilities may be reluctant to assume the costs of these upgrades for fear that they will not be approved by the FERC for cost recovery in the event of "abandonment," or not being used by future generators.

This concern was clearly articulated in SCE's petition for declaratory order seeking rolled-in rate treatment for the Antelope Transmission Projects.[16] In rendering its decision in response to SCE's petition, the FERC order provided the cost recovery assurance sought by SCE for two of the three transmission projects (Segments 1 and 2) presented by SCE, granting rolled in rate-treatment for all prudently incurred costs, regardless of abandonment or cancellation of the

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[15] In either case, the costs of network upgrades are ultimately rolled into transmission rates. If generators finance the construction of network upgrades they are made whole for these investments over a five year period.

[16] Southern California Edison Company's Petition for Declaratory Order, pp. 4-7, March 23, 2005.

project facilities.[17] FERC's willingness to authorize cost recovery was based on its view that these segments are appropriately considered network upgrades and the fact that SCE did not have control over the ultimate materialization of the anticipated future generators. This outcome suggests, that at least for network upgrades, utility financing is a viable option.

Despite this favorable outcome with respect to network upgrades, we view the ability of utilities to elect to pay for network upgrades and seek cost recovery through the TAC as only a partial solution for two reasons. First, the FERC decision was specific to segments 1 and 2 of the Antelope Transmission Projects, and thus does not provide any guarantee that future applications seeking rolled-in treatment for similar projects will be approved. Second, FERC rejected rolled in treatment for segment 3 of the Antelope Transmission Projects, on the grounds that the configuration of the project is inconsistent with its definition of a network upgrade and thus the project is ineligible for rolled-in rate treatment.

As with the decision to authorize rolled-in treatment for Segments 1 and 2, the decision to reject rolled-in treatment for Segment 3 is no guarantee that similar projects that come before FERC in the future will be denied rolled-in treatment. Nevertheless, barring future changes to the CAISO tariff, it is reasonable to assume that similar gen-tie projects will not be approved for cost recovery through the TAC. Thus for transmission projects that are likely to be classified by FERC as gen-tie facilities and for which the most economic build-

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[17] FERC Order on Petition for Declaratory Order, Commission Determination, order F. (112 FERC 61,014) This represents a departure from the conventional rules applied to abandoned plant which limit the utilities ability to recover prudently incurred costs for abandoned or cancelled facilities to fifty percent.

out involves capacity expansions beyond what is needed for the typical project, the CAISO and FERC tariffs provide no relief. Developers are unable or unwilling to finance the costs of these facilities, and utilities have no assurance under the existing CAISO tariff of cost recovery if they choose to build them.

Section 399.25 is intended to cut this Gordian knot, by providing a "backstop" mechanism through which cost recovery for transmission facilities deemed necessary to facilitate achievement of California's renewable energy goals can be assured. Parties raised a range of issues regarding implementation of § 399.25 cost recovery mechanism in this proceeding, including the eligibility criteria, the need for a finding on network benefits, ratemaking treatment, and cost allocation. We address each issue raised in the comments and briefs, making policy decisions as appropriate to implement the backstop cost recovery provisions of § 399.25.

A. Revisions to D.03-07-033

In the preliminary scoping memo included in the OII, we requested comment on the need to revise certain findings adopted in D.03-07-033. In particular, in light of SCE's application for a CPCN for Segments 2 and 3 of the Antelope Transmission Projects,[18] we requested comments on whether we should reconsider our prior decision limiting § 399.25 backstop cost recovery to network upgrades. As stated in the OII, our concern was that our prior interpretation of § 399.25 limiting backstop cost recovery to network facilities was too narrow and would hamper our efforts to facilitate the RPS objectives.

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[18] Application (A) 04-12-008.

We also requested comment on the need to reconsider our prior determination that the Commission must make a finding that the proposed transmission upgrades provide "benefits to the transmission network" in order for the upgrades to be considered eligible for § 399.25 cost recovery.

All parties agree that we should revise our earlier determinations. In its comments, SCE notes that although subsection (b) of § 399.25 lists four actions required of, or available to, the Commission, the list implies no interdependence among the four, and because network benefits are not mentioned in § 399.25(b)(4), cost recovery is available without a finding of network benefits.

According to SCE, subsection (b)(4) of § 399.25 requires the Commission to allow recovery in retail rates of increases in transmission costs if three criteria are met: (1) the costs are prudent, (2) the cost are not approved by FERC for recovery in transmission rates, and (3) the facilities are necessary to facilitate the renewable power goals. Agreeing with SCE, the CAISO and other parties suggest that a detailed and protracted assessment regarding how to define and measure potential network benefits would not be an efficient use of the Commission's resources. The parties maintain that, although the statute requires the Commission to attempt to make findings concerning network benefits, if a finding of network benefits cannot be supported by the record, § 399.25(b)(4) independently mandates that the prudent costs of RPS-necessary transmission are to be reflected in retail rates.

We agree with the majority of parties that the determination of network benefits is not a prerequisite for § 399.25 cost recovery based on a plain reading of the statute. As noted by the parties, the language of § 399.25(b)(4) does not require transmission facilities to be classified as "network" nor does it require a finding of "network benefits" to allow cost recovery through retail rates. While

§ 399.25(b)(1) requires the Commission to determine whether the network supports findings regarding network benefits, if such findings are not made, § 399.25(b)(4) still applies. The evaluation of potential network benefits will take place in the applicable certificate proceedings.

D.03-07-033 also included a finding that gen-tie facilities would not be eligible for § 399.25 cost recovery. Our decision was based on the assumption that, since § 399.25 only applies to certificate applications for transmission upgrades subject to Commission review, it would not apply to gen-tie facilities, because gen-tie facilities are typically not the subject of CPCN or PTC applications. Gen-tie facilities, defined as transmission facilities designed to bring power from a generation plant to the first point of interconnection with the existing transmission grid, are generally permitted, constructed, and financed as part of the cost of generation projects and are often sited by the CEC along with the generation project.[19]

However, as SCE points out, at the time D.03-07-033 was issued the Commission was not considering specific, proposed facilities such as SCE's application for a certificate to construct Segments 2 and 3 of the Antelope Transmission Projects[20], and there were no facts before the Commission to facilitate a more detailed interpretation of the statute.

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[19] The CEC sites thermal generation projects of 50 megawatts or above. Smaller and non-thermal projects are typically sited under local permitting authority.

[20] A.04-12-008, Amended Application of Southern California Edison Company for a CPCN to Construct the Antelope-Vincent and Antelope-Tehachapi Transmission Projects, at 15.

All parties now recommend that Commission consider revising its prior determination to accept that the cost recovery provisions of § 399.25 apply to certain gen-tie facilities as well as network facilities. In support of this recommendation, the CAISO notes that nothing in the statute prevents the extension of § 399.25 rate recovery to gen-ties and in fact, SCE's Antelope lines demonstrate that a primary value of § 399.25 lies precisely in its application to non-network facilities.

TURN agrees, and points out that the legislature did not intend for the Commission to provide the § 399.25 backstop only to ensure cost recovery for facilities already eligible for similar treatment, but rather to extend this policy to certain transmission projects not fitting the network description but deemed necessary to achieve the objectives of the RPS program.

As discussed above, § 399.25(b)(4) does not require the facilities to be network, nor does it exclude gen-tie facilities Upon further review, we find it appropriate to modify our interpretation of this provision. We find that § 399.25 applies to applications for a certificate authorizing construction of new transmission facilities, either network or gen-tie, that are deemed necessary to facilitate the achievement of the RPS goals.

We reiterate our prior finding that § 399.25 does not apply to facilities that are not constructed by a utility and thus are not brought to the Commission for certification. The relevant portion of § 399.25 (a) reads:

> [A]n application of an electrical corporation for a certificate authorizing the construction of new transmission facilities shall be deemed to be necessary to the provision of electric service for purposes of any determination made under Section 1003 if the commission finds that the new facility is necessary to facilitate achievement of the renewable power goals established in Article 16 (commencing with Section 399.11).

Furthermore, while we agree with IEP that the statute can be applied to both new renewable generation requiring transmission upgrades and to existing projects that repower or expand their facilities resulting in a need for new transmission facilities, the provisions of § 399.25 apply only to applications before the Commission from an electrical corporation for a certificate authorizing the construction of new facilities that meet certain criteria.

B. Eligibility for § 399.25 Cost Recovery

The parties maintain that the Commission can facilitate the objectives of the RPS program by providing upfront criteria to identify transmission projects that are eligible for § 399.25 cost recovery. CalWEA suggests that the Commission should avoid reading the "necessary to facilitate" language to require certainty as to which projects should be eligible and instead look to an array of evidence, without setting particular thresholds regarding actual project developments.

CEERT suggests that the Commission find that transmission infrastructure planned and built to access known, concentrated renewable resources areas in California and to serve multiple renewable generators should be deemed necessary to facilitate achievement of the renewable power goals of the RPS program. CEERT notes that the renewable resource areas studied by the Tehachapi Collaborative Study Group and the Imperial Valley Collaborative Study Group are "known, concentrated renewable resource areas." It asserts that "shared gen-tie" transmission projects designed to access those areas should be deemed eligible for §399.25 cost recovery.

The Joint Parties (PG&E, SDG&E, SCE, and the CAISO) offer more specific criteria. The Joint Parties recommend that the Commission should use the following three criteria to identify projects that are eligible for § 399.25 backstop cost recovery:

- any transmission upgrade that is required to interconnect an RPS-eligible resource with a signed power purchase agreement,
- any project that the CAISO determines to be needed pursuant to Section 3.2 of its tariff that will also provide RPS-related benefits, or
- any high-voltage, bulk transfer generation-tie line serving multiple generators that allows utilities to access least-cost, best-fit resources and would not otherwise be constructed.

The Joint Parties explain, however, that the individual transmission facilities necessary for generation developers to interconnect to a high voltage bulk transfer line should remain the responsibility of the generator.

TURN agrees that the Commission should provide guidance regarding eligibility for § 399.25 backstop cost recovery, but cautions against expanding backstop cost recovery to any new transmission project preferred by a utility. TURN also recommends adopting a "diversity test" to ensure that ratepayer funded upgrades are designed to accommodate multiple generators and do not benefit a single developer.

TURN recognizes that it may prove impossible to show significant developer activity and financial commitment (such as signed power purchase agreements, requests for system Impact Studies, and interconnection requests) absent a guarantee that transmission will be constructed to allow for the delivery of generation. Therefore, TURN suggests that the "necessary to facilitate" standard can be satisfied through a two-part analysis consisting of the Commission determining first whether the transmission would enable the construction of any projects selected by a retail seller through the least-cost, best-fit evaluation, and second, whether the development in the region is likely to be needed to allow the achievement of identified renewable procurement targets for retail sellers subject to the RPS program.

Vulcan opposes any criteria that would limit § 399.25 cost recovery to shared facilities. Vulcan notes that a gen-tie could be either shared by several intermittent generators or utilized by a single baseload renewable generator. Vulcan argues that transmission facilities necessary to connect individual baseload renewable projects with executed power purchase agreements should be considered eligible for § 399.25 cost recovery since baseload renewable projects, unlike intermittent power sources, not only would allow the load serving entity to meet its RPS goals, but also would provide network benefits to the system as a whole. Stirling supports this contention, stating that one direct way for the Commission to provide renewable project developers and utility transmission facility owners with necessary assurances of cost recovery for transmission network system upgrades that will be integrated with the grid is to adopt a policy statement that rolled-in rate treatment will be automatically afforded transmission system upgrades for projects that hold power purchase agreements that have been approved by the Commission.

In considering these arguments and implementing § 399.25, we remind parties that § 399.25 is intended to supplement the existing process in circumstances where that process impedes the development of transmission infrastructure necessary to facilitate the state's renewable energy goals. In our view, the scenarios under which the existing processes are likely to impede the development of transmission infrastructure to access renewable resources are limited to those circumstances where the economic expansion of transmission infrastructure requires capacity increases that exceed the capacity requirements of the typical project. This occurs primarily, if not exclusively, in those situations where a large quantity of renewable resources are highly concentrated. As described above, it is under these circumstances that, absent § 399.25, for transmission to be built in as economic a manner as possible, either generators would find themselves paying for capacity in excess of their incremental needs, thus imposing undue burden on their projects, or utilities would find themselves paying for excess transmission capacity without adequate assurance that they will be able to recover the associated costs.

As SCE points out, there are sound reasons for differentiating between lines that link one generation developer's resources with the grid and high-voltage, bulk-transfer, gen-tie lines serving multiple generators. In particular, the bulk transfer gen-tie lines that serve multiple generators will be easier to develop in a more economic, environmentally-friendly way if they are planned to serve the needs of a large area or several developers. Otherwise, a far greater number of lines by each generator, all competing for right-of-way and causing environmental effects, would have to be constructed. PG&E concurs, stating that the § 399.25 cost recovery should remain a backstop, for use when existing regulatory structures prove inadequate. Any criteria we adopt should harmonize the intention of the statute with the existing regulatory mechanisms.

First, we consider the Joint Parties recommendation that transmission facilities determined through the interconnection process to be needed to interconnect and or deliver power from an RPS-eligible resource whose developer has entered into a Commission-approved power purchase agreement should be deemed eligible for § 399.25 cost recovery.

In our opinion, the fact that a RPS project may count towards meeting RPS goals does not, in and of itself, mean that all the associated transmission facilities are "necessary" to facilitate the goals of the RPS. Under current FERC policy, a single line interconnecting one generation developer's resources with the grid is paid for by the generation developer. If the line is not constructed by a utility, it is not eligible for § 399.25 cost recovery.

Consequently, while we agree with the parties that transmission facilities that are required to interconnect an RPS-eligible resource with an approved power purchase agreement are eligible for § 399.25 cost recovery, we expect that transmission upgrades designed to facilitate the achievement of the RPS goals will accommodate multiple RPS-eligible resources. Providing backstop cost recovery for individual gen-tie facilities would unfairly shift the risk and cost of the interconnection facilities to the utility's retail ratepayers and protect the utilities and developers from inefficient procurement decisions.

Next, in light of our determination in D.04-06-010 regarding the magnitude and concentration of the renewable resources located in the Tehachapi area and identified in the November 19, 2003 "Renewable Resource Development Report," "Renewable Resources Development Report," CEC Publication Number 500-03-030F, November 2003, we find that the costs associated with high-voltage, bulk-transfer, multi-user transmission facilities, whether classified as "network" or gen-tie, proposed to access known "Renewable Resource Areas" where economic expansion requires capacity increases that exceed the incremental needs of the typical project are eligible for cost recovery under § 399.25. Therefore, we find that any high-voltage, bulk-transfer transmission facilities serving multiple generators that provide access to least-cost and best-fit renewable resources and would not otherwise be constructed are eligible for § 399.25 cost recovery.

Finally, we decline to approve the recommendation that the Commission automatically deem any project that the CAISO determines to be needed pursuant to Section 3.2 of its tariff that will also provide RPS-related benefits to be "necessary to facilitate the RPS goals." We find this criterion unnecessary since projects needed to facilitate the RPS goals should meet one of the prior two criterion, and projects required by the CAISO for economic or reliability purposes should qualify for cost recovery at FERC.

We also note a finding of eligibility for cost recovery is a necessary, though not sufficient, condition for cost recovery through retail rates under § 399.25. Any proposed project must still be approved through a certificate proceeding, where the Commission would conduct CEQA review pursuant to G.O. 131-D.[21] Finding that a particular project is "necessary" for the achievement of the RPS goals assumes that the Commission has considered the impacts of, and the alternatives to, the project as required by CEQA. This decision maintains the general rule adopted in D.03-07-033, that the Commission will make the finding of "necessity" in response to the utility's application for a CPCN or PTC for the transmission project.

The utility must demonstrate in the certificate proceeding that the subject facilities are necessary to achieve the objectives of the RPS program before cost recovery through retail rates will be granted. The degree of certainty required for such a showing will depend on the magnitude of costs at stake. We agree with the parties that in certain cases, it will be necessary to consider the status results of the RPS compliance to date, including, but not limited to any approved procurement plans, the results of RPS solicitations, existing bilateral contracts,

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[21] See GO 131-D Sections IX.A.1.e. and IX.B.1.c. In addition, CEQA requires the Commission to consider project alternatives in the CPCN or PTC application process.

the number of short listed bidders, the transmission cost studies and requests for system impact studies, etc. This type of probative review will occur as part of the certificate proceeding for a proposed facility.

Given FERC's decision on SCE's Petition for Declaratory Order, granting rolled-in rate treatment for Segments 1 and 2 of SCE's Antelope Projects, retail ratepayer risk is somewhat limited for network facilities. For facilities classified as "gen-ties," however, retail ratepayer risk exposure remains high. In this situation, we would expect to see a much stronger showing to support a claim that a facility is "necessary to facilitate the achievement of the RPS goals." For example, we would not expect to grant § 399.25 cost recovery treatment to gen-tie facilities absent at least one approved RPS contract. Making the backstop cost recovery contingent upon an RPS contract is consistent with the requirement in the statute that the transmission project be "necessary" to the achievement of RPS goals. As discussed above, § 399.25 is not meant to substitute for the existing cost recovery mechanisms available to support transmission development, nor is it intended to change the ultimate cost responsibility of generators and utility ratepayers.

C. Section 399.25 Cost Recovery Mechanism

The utilities request that we establish the specific ratemaking mechanism for backstop cost recovery under § 399.25 in this order. As discussed above, § 399.25(b)(2) requires the Commission to direct "the utility to which the generator will be interconnected, where the direction is not preempted by federal law, to seek the recovery through general transmission rates of the costs associated with the transmission facilities." In addition, § 399.25(b)(3) requires the Commission to support the utility's application at FERC. Thus, even though the "backstop" exists in § 399.25(b)(4), the intent of the legislation is clear that recovery of renewable transmission costs from retail ratepayers should be made available as a last resort. Therefore, we expect that in addition to filing a certificate application here for any requested facilities, the utilities will also seek recovery at FERC through general transmission rates.

TURN notes that the Commission should consider approving cost recovery treatment for eligible projects in advance of FERC action if the project is unlikely to be eligible for rolled in ratemaking under the existing FERC policy. TURN argues that unless there are clear indications that the facility qualifies as a network upgrade, the Commission should not defer a cost recovery request.

For recovery of costs eligible for § 399.25 treatment, SCE proposes a ratemaking mechanism similar to the one it proposed in A.04-12-008. SCE states that it is recording the costs and capital related revenue requirement for the Antelope Transmission Project in the Antelope Transmission Projects Memorandum Account (ATPMA) approved by the Commission in response to SCE Advice Letter 1833-E filed on December 13, 2004. SCE states that when facilities are placed into operation, SCE will record the costs and capital related revenue requirement in the ATPMA. If FERC approves cost recovery, SCE will remove costs from the ATPMA, and presumably, record those costs in the relevant FERC accounts for recovery in SCE's Transmission Revenue Requirement (TRR) proceedings. If FERC does not allow recovery of certain costs of the Antelope Transmission Project, as it has already indicated with respect to Segment 3, SCE would transfer the subject costs recorded in the ATPMA to the SCE Base Revenue Requirement Balancing Account (BRRBA).

In this proceeding, as in A.04-12-008, SCE recommends that the entries in the ATPMA be reviewed in SCE's annual Energy Resource Recovery Account (ERRA) Forecast of Operations proceeding. SCE suggests that, until such time that additions to rate base, costs, and capital-related revenue requirement associated with the Antelope Transmission Project can be reflected in SCE's general rate case, SCE will make entries in the BRRBA for review in the ERRA. In future general rate cases, SCE would present the ERRA-reviewed costs as part of its base rate revenue requirement request.

No other party suggested a specific ratemaking mechanism other than to note that recovery of costs should only be authorized after the Commission has offset contributions from project developers. We will adopt SCE's recommended process with one modification. At such time as a utility files an application for a certificate to construct transmission line facilities that it believes are subject to § 399.25 cost recovery, the utility shall also file an Advice Letter requesting permission to establish a memorandum account to record the costs of the facilities. If the proposed facilities are granted rolled-in rate treatment at FERC, the costs recorded would be removed from the memorandum account and included in the utility's TRR proceeding at FERC. If the proposed facilities are not granted rolled-in rate treatment at FERC, the costs recorded in the memorandum account should be included as part of the rate base, costs, and capital-related revenue requirement request to be reviewed in the utility's next general rate case. Costs would be offset by the revenues received from generators who take service on the subject facilities. Review or audit of the costs should occur in the utility's general rate case, not the ERRA. The ERRA proceedings are intended as a six-month forecast of energy-related and procurement expenses, and are not suitable for review of or setting revenue requirements for transmission costs.

D. Cost Allocation

The discussion on cost allocation provided in the parties' briefs largely focused on the question of whether the increased costs associated with transmission facilities necessary to facilitate the RPS goals should be recovered from all transmission customers or the retail customers of the transmission owners. The Joint Parties maintain that any costs of RPS-necessary network facilities that are not included in FERC-jurisdictional rates should be allocated to the retail customers of all three investor-owned utilities. The costs of gen-tie facilities that cannot be collected from generators should be allocated to the retail customers of the utility constructing the upgrade. The Joint Parties also state that for eligible gen-tie facilities, to the extent up front financing was provided by the utility, gen-tie costs should be recovered pro-rata from the RPS generators interconnected to it under FERC rates.

The Joint Parties explain that their recommendation is consistent with FERC's existing cost recovery policies for the CAISO control area, in which the cost of all high voltage transmission facilities (operated at or above 200kV) are socialized across all CAISO loads, while the costs of lower voltage transmission facilities within each utility's service area are recovered only from the loads within that utility's service area. The Joint Parties recommend that the costs recovered pursuant to §399.25 be allocated on a similar basis.

CEERT comments that reliance on balancing account mechanisms for tracking these costs is appropriate, so long as costs recovered through retail rates are net of any contributions received from generators.

TURN suggests that the Commission adopt the following three principles for any project eligible for the 399.25 backstop. First, the Commission should allow the transmission owner to assess costs on all interconnected generators using the facilities on a pro rata basis. Second, costs of excess transmission capacity should be spread to all retail sellers under the Commission jurisdiction in a manner similar to the allocation of the Transmission Access Charges collected by the CAISO. Third, costs should be collected from retail customers through the creation of a new "renewable transmission" rate component with customers assessed costs based on an equal cents per kilowatt-hour allocation methodology.

TURN opposes limiting § 399.25 cost recovery to the ratepayers of the transmission owner, on the grounds that this approach would require the customers of a particular IOU to pay for transmission which enables the development of renewable generation benefiting the entire state. TURN also disagrees with SDG&E's recommendation that costs of unutilized capacity should be recovered through distribution rates, arguing that distribution rates should not be used as a "catch-all" for any costs the Commission seeks to impose on retail ratepayers. TURN suggests that since new renewable transmission is driven by the energy needs of a retail seller, is unrelated to any determination of peak load requirements, and is not correlated to the cost of meters, transformers, service drops and customer billing, it is rational, and fair to assess the costs of renewable transmission based on the energy usage of each customer class, using an equal cents per kilowatt-hour methodology.

We emphasize that our intent in granting § 399.25 cost recovery to the utilities is not to relieve the generators of their ultimate cost responsibility for upgrade costs, but instead is to facilitate up-front funding of economically sized upgrades wherever possible, and to ensure that sufficient transmission exists to meet the RPS goals. We find that the discussion on cost allocation was largely inadequate to develop a specific cost allocation methodology. However, as a starting point, we affirm that it is our intent to allocate the excess costs associated with renewable transmission to the ratepayers of all jurisdictional utilities, where appropriate. This is consistent with our belief that the benefits of the RPS program in general, and transmission access to renewable resources in particular, accrues to all users of the California grid, not merely the customers of the utility constructing the transmission facilities. We therefore invite the utilities to file an application for allocation of renewable transmission costs when facilities subject to § 399.25 cost recovery are placed in service.

We also agree with TURN that cost associated with renewable transmission facilities to be recovered from retail ratepayers pursuant to § 399.25 should not be recovered through distribution rates, and should instead be recovered through a separate renewable transmission rate component.

E. Access to Renewable Transmission Facilities

The ACR requested comments on whether it was necessary or appropriate to attempt to ensure access on transmission facilities funded under the backstop cost recovery provisions set forth in § 399.25 for renewable resources.

The parties responded by noting that access by renewable resources to transmission facilities that are subject to cost recovery under § 399.25 is a non-issue because all transmission facilities built by the utilities will be turned over to CAISO operational control, and will therefore be subject to FERC-approved open access rules which provide grid access on a nondiscriminatory basis based on competitive bids. Any market participant desiring access to the CAISO grid, and willing to pay the marginal costs of obtaining such access (paying for the marginal costs of congestion and losses), is assured access.

F. Construction Triggers

The ACR requested comments on what triggers or conditions, if any, were necessary to protect ratepayers from stranded or excessive costs associated with the permitting and construction of large scale transmission upgrades. The majority of the parties, including the utilities and the CAISO, do not recommend establishing specific triggering criteria for future transmission projects at this time. Instead, they suggest that the Commission consider developing permitting and construction triggers on a case-by-case basis in the applicable certificate applications. Such triggers could reflect the need for additional renewable power to meet RPS goals, the level of utilization and/or commitment for existing phases and proposed phases, and the potential market for additional renewable power.

Alternatively, SDG&E suggests that to minimize the risk of stranded investment, "trunk lines" could be permitted in advance of contractual commitments to facilitate their development in the future. Then, once permits are in hand, the utility could hold an open season to solicit contracts for the development of new renewable projects. Actual construction of the trunk line would only commence once contracts are in place ensuring that a sufficient quantity of generation will be built. Under SDG&E's proposal, the subject transmission facilities would only be built upon a determination that there were sufficient commitments to add generation in the remote area, so there should be no "under-utilization" of transmission capacity and the Commission's backstop ratemaking authority should permit transmission providers to recovery the full amount of costs that the FERC does not allow to be recovered through FERC-jurisdictional rates.

We agree with the parties' recommendation to consider any necessary triggers in the applicable certificate proceedings.

V. Comments on Draft Decision

The draft decision of Administrative Law Judge (ALJ) Halligan was mailed to the parties in this proceeding in accordance with Section 311(g)(1) and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed on ______ by ______. Reply comments were filed on ______ by ______.

VI. Assignment of Proceeding

Dian Grueneich is the assigned Commissioner and Julie Halligan is the assigned ALJ in this proceeding.

Findings of Fact

1. The provisions of § 399.25 apply to applications for transmission line construction subject to the Commission's siting jurisdiction, either network or gen-tie, that are deemed necessary to facilitate the achievement of the RPS goals.

2. A finding of "network benefits" pursuant to § 399.25(b)(1) is not a prerequisite for backstop cost recovery under § 399.25(b)(4); the two provisions on the code function independently of one another.

3. High voltage, bulk-transfer transmission facilities, whether classified as network or gen-tie, that are designed to serve multiple RPS-eligible generators where it has been established that the amount of added transmission capacity will likely be utilized by RPS-eligible generation projects within a reasonable period of time are eligible for § 399.25 cost recovery.

4. New transmission facilities needed to interconnect on RPS-eligible resource whose developer has entered into a Commission-approved power purchase agreement are eligible for § 399.25 cost recovery.

5. To protect ratepayers from the risk associated with unnecessary facilities, we do not anticipate finding gen-tie facilities to be necessary to facilitate the achievements of the RPS goals absent at least one approved RPS contract.

6. Costs associated with renewable transmission facilities to be recovered from retail ratepayers pursuant to §399.25 should not be recovered through distribution rates.

Conclusions of Law

1. The Commission's ability to authorize retail rate recovery of transmission upgrade costs pursuant to § 399.25(b)(4) does not interfere with the FERC's jurisdiction over transmission ratemaking such that it would be preempted by federal law.

2. The Commission does not have the authority to require transmission owners to provide up-front funding for transmission upgrades.

3. In order to proceed as expeditiously as possible with the implementation of § 399.25, this decision should be effective today.

INTERIM ORDER

IT IS ORDERED that:

1. The provisions of Section 399.25 apply to transmission facilities that come before the Commission in the form of a Certificate of Public Convenience and Necessity or Permit to Construct application and that are deemed necessary to facilitate the Renewable Portfolio Standard (RPS) goals through that process.

2. The provisions of § 399.25 apply to both "network" transmission facilities and high-voltage generation-tie (gen-tie) transmission facilities that are deemed necessary to facilitate the achievement of the RPS goals.

3. Transmission projects that meet the following criteria are eligible for § 399.25 cost recovery: (1) new high voltage, bulk-transfer, transmission facilities, whether classified as network or gen-tie, that are designed to serve multiple RPS-eligible generators where it has been established that the amount of added transmission capacity will be likely to be utilized by RPS-eligible generation projects with a reasonable period of time, and (2) transmission upgrades that are required to connect RPS-eligible resources with approved power purchase contracts.

This order is effective today.

Dated ___________________, at San Francisco, California.

ATTACHMENT 1

LIST OF ACRONYMS AND ABBREVIATIONS

AB – Assembly Bill

ALJ – Administrative Law Judge

CAISO – California Independent System Operator

CalWEA – California Wind Energy Association

CEC – California Energy Commission

CEERT – Center for Energy Efficiency and Renewable Technologies

CEQA – California Environmental Quality Act

CPCN – Certificate of Public Convenience and Necessity

FERC – Federal Energy Regulatory Commission

GO – General Order

I. - Investigation

IEP – Independent Energy Producers

IOU – Investor-Owned Utility

PG&E – Pacific Gas and Electric Company

PTC – Permit to Construct

R. - Rulemaking

RPS – Renewable Portfolio Standard

SB – Senate Bill

SDG&E – San Diego Gas and Electric Company

SCE – Southern California Edison Company

TURN – The Utility Reform Network

(END OF ATTACHMENT 1)